INDUSTRIAL MINERALS ASSOCIATION – NORTH AMERICA (IMA-NA)
SODA ASH and BORATES SECTIONS
GREENHOUSE GAS INVENTORY PROTOCOL

1.0 INTRODUCTION

The borates and soda ash industry in the United States has initiated a project to compile a greenhouse gas (GHG) inventory for U.S-based mining, mineral processing and chemical processing associated with the production of borate compounds, soda ash and related compounds.

This protocol is designed to assure that the greenhouse gas inventory developed by this industry sector conforms to the guidelines outlined in "The Greenhouse Gas Protocol," published jointly by the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI). Specifically, this protocol is intended to assure that the GHG inventory meets the criteria of:

- Relevance,
- Completeness,
- Consistency,
- Transparency. and
- Accuracy

2.0 OVERVIEW OF GHG INVENTORY PROJECT

The IMA-NA is an appropriate organization to manage the collection of greenhouse gas data since all of the U.S. producers of borates and soda ash currently are members.

2.1 Industrial Sector

All of the nation's soda ash production occurs in southwest Wyoming, and California. The nation's borates production is limited to California. The companies participating in this survey are:

- FMC Corporation (Soda Ash)
- General Chemical Industrial Products, Inc. (Soda Ash)
- IMC Chemicals, Inc. (Borates and Soda Ash)
- OCI Chemical Corporation (Soda Ash)
- Solvay Chemicals, Inc. (Soda Ash)
- U.S. Borax (Borates)

2.2 Operations Covered

All activities involved in removing ore from the mine sites, processing the ore to product grade borates or sodium carbonate compounds, and the transportation of these products to customers (internal and external to the producer company) were considered covered by the scope of this survey.

In addition, the sites involved in this survey also produce other products that are not classified as borates or soda ash-related compounds. These products utilize the same energy systems as the covered product lines and are not easily separated out for inventory purposes. Further, the relative size of these product streams is small. For these reasons, the working group that developed this protocol decided to include these product lines in the inventory, i.e., the energy consumed and greenhouse gases generated from the production of these products are included in the inventory as is the total production volume of these products.

2.3 Time Period Covered

IMA-NA's inventory tracking began with the year 2000 and will continue through the year 2012. It is recognized that the President's ClimateVISION initiative calls for a national goal of 18% reduction in GHG Intensity using 2002 as a base year and 2012 as a target year.

2.4 GHG Intensity

Under the President's ClimateVISION Program, GHG Intensity is defined as total GHGs divided by the nation's Gross Domestic Product (GDP). For the borates and soda ash industry sector, a more appropriate measure is production volume, or more accurately, mass produced. This protocol therefore defines GHG Intensity as tons of CO2e per ton of product (where tons are short tons).

2.5 Greenhouse Gas as CO2-Equivalent

The operative measure used in this inventory is tons of CO2-equivalent (CO2e). The CO2e for carbon dioxide is by definition 1. Most of the GHG emissions from this industry sector are comprised of carbon dioxide. However, a significant amount of non-carbon dioxide GHGs is emitted, notably as methane from underground trona mines. GHG emissions are converted to CO2e using each chemical's "Global Warming Potential" (GWP) factor as published in the Intergovernmental Panel on Climate Change's Third Assessment Report (TAR). [Note: National Inventories use the IPCC guidance procedures issued in 1996. This guidance relies on the IPCC's 1995 Second Assessment Report (SAR) and the GWPs published therein. The IMA-NA Soda Ash/Borates Sections are considering revising this protocol to use the older SAR factors to put the group in line with the USEPA, the USDOE and other governmental bodies inside and outside the United States.]

3.0 OPERATIONAL BOUNDARIES

The operational boundaries adhere to the guidance provided in the WBCSD/WRI "GHG Inventory Protocol." In applying this guidance, it is important to recognize that mining and mineral processing is a relatively energy-intensive activity. This consideration was used to greatly simply the survey by eliminating a number of activities (particularly Scope 3 activities) that are not numerically significant.

3.1 Direct GHG Emissions (Scope 1 Activities)

GHG emissions generated on participating company sites are considered as "Scope 1" emissions by the WBCSD/WRI. These emissions are the largest single component of this survey. Direct GHG emissions include:

- On-site combustion to generate electricity, heat or steam.
- Physical or chemical processing of raw materials and intermediates.
- On-site transportation of raw materials, intermediates, products and personnel to the extent that the site supplies the fuel for vehicles or transportation systems. Vehicles that are fueled off-site are considered de minimus contributors to the site's GHG Inventory and data are not collected for these sources.
- Fugitive and point emissions associated with mining activities (e.g., methane releases).

3.1.1 On-site Combustion for Electricity, Heat and Steam

Participating companies burn coal, natural gas and fuel oil as well as some other fuels in smaller quantities on their mining and processing sites. The CO2e for the combustion of fossil fuels was calculated using one of two basic methods:

1. Site Calculation Using Fuel Analysis: Site personnel were given the option of doing their own calculation for the CO2 emitted from on-site combustion. To perform this calculation, the site requires that its fuel supplier provide a fuel analysis or the site perform a fuel analysis. The analysis provides the carbon content for a unit measure of fuel. For natural gas, the unit of measure is 1000 cubic feet (MCF) at 1 Atm. pressure and 60 deg F. For liquid fuels, the measure was 1000 U.S. gallons and for solid fuels, the measure was dry short tons.
2. Use Default CO2 USDOE Emission Factors: Site personnel could also calculate the CO2 emissions by using the USDOE default emission factors. These factors are listed in the survey instructions that appear in Appendix A.

The CO2e associated with N2O and methane emissions from the combustion processes were evaluated using the USEPA AP-42 Emission Factors Manual. The CO2e from N2O and methane emitted from the types of combustion units used at participating companies are well below 1%. Therefore, no effort was made to estimate these non-CO2 emissions and CO2 emissions are used as a reasonable approximation of CO2e for on-site combustion.

Further, participating companies are engaged in exporting electricity off-site for use by other entities. The CO2e associated with this electricity was calculated using the "CHP Option 1" methodology found in the WBCSD/WRI guidance on stationary combustion. For more details, see the survey instructions in Appendix A. The sites calculate the total GHGs emitted from the production of this electricity, but only those GHGs associated with the electricity consumed by the participating companies operations are included as Direct GHGs in this inventory. The GHGs associated with exported electricity are kept as supporting details.

3.1.2 Physical or Chemical Processing

The processing of trona ore into soda ash and related products involves the generation of CO2 in stoichiometric quantities. These chemical pathways are well defined and generally accepted within the industry. Each soda ash company participating in the survey calculated process emissions of CO2 associated with the physical and chemical processing of trona and downstream chemicals using these accepted methods.

3.1.3 On-site Transport

Transport of materials and people on-site is fairly energy-intensive and most of this activity relies on fuels or energy that are brought on-site and tracked. The fuels and energy used for these activities are accounted for in the survey. Some incidental vehicle use on-site may rely on fuels obtained off-site (generally from local service stations) and this incidental fuel may not be captured by the site's primary systems for tracking energy and fuel use. This incidental fuel use is considered trivial compared to the fuel and energy use tracked by the sites and therefore no additional effort was expended to obtain those data.

3.1.4 Incidental Releases (Fugitive and Point Source)

The only significant emission identified in this category was methane releases from the subsurface mining of trona ore. Trona deposits occur in the same general area as oil shales and relatively dispersed deposits of natural gas. Mining activities result in the incidental release of methane into the mine shafts. Release of methane into a confined space poses safety concerns and is subject to management standards administered by the U.S. Mine Safety and Health Administration (MSHA). MSHA requires that all trona mines implement engineering controls to adequately sweep methane from the mine shafts to prevent gas fires or explosions. The methane is swept up the ventilation exhaust shafts and discharged to atmosphere. Monthly testing is conducted on these exhaust vents for volume and methane concentration. Site personnel use these data to calculate the annual methane releases.

3.2 Indirect GHG Emissions (Scope 2 Activities)

The WBCSD/WRI classify GHG emissions associated with production of imported electricity and steam as Scope activities. Participating companies import a significant amount of energy and Scope 2 activities are included in this survey. Imported electricity is supplied by local power companies and imported steam generally is supplied by a neighboring industry operating a combined heat-and-power generation unit (CHP).

The CO2e emission factor for imported electricity was obtained in one of two ways:

1. Provided by the power company as the best estimate for power supplied to the region in which the plant is located, or
2. The default USDOE factor for the state in which the plant is located (see Appendix C of the USDOE's Instructions for Form EIA-1605).

For imported steam, site personnel contacted their supplier to obtain an emission factor. If the factor was not calculated in conformance with WBCSD/WRI guidance, the site sought sufficient information to calculate the proper factor. For more details, see the survey instructions in Appendix A.

3.3 Other Indirect GHG Emissions (Scope 3 Activities)

Other indirect GHG emissions (not covered under Scope 1 or 2) are recognized as being numerically significant, particularly the transportation of products to market. However, at this time, the borates and soda ash industry is focusing only on Scope 1 and 2 activities.

4.0 ESTIMATION METHODS FOR MAJOR SOURCES OF GHGs

Additional detail is provided for several of the major sources of GHGs covered in this survey, specifically:

- On-site combustion for steam, heat and/or electric power
- Allocation of GHGs to steam and power for CHPs (for imported steam and exported electricity)
- Process emissions of CO2 from trona processing and downstream chemical processing of soda ash products
- Methane emissions from trona mines

Calculation methods for other sources of GHGs (e.g., imported electricity) are considered sufficiently simple that no further explanation is provided.

For all GHG calculations, participating companies are instructed to adhere to good engineering practice and to document all assumptions and calculation methods.

4.1 On-Site Combustion Processes

Site personnel are encouraged to estimate CO2 from combustion using fuel analysis data for the fuels combusted over the course of the year. Fossil fuels vary considerably in their composition and therefore default emission factors can only provide an approximation of the GHGs emitted. Default factors from the USDOE or USEPA are acceptable as a last resort, but using actual fuel data is the preferred method.

4.1.1 <u>Estimating CO2 Emissions From Fuel Data</u>

Fuel analysis data are needed for each source of fuel and should be reviewed over time. If the source of fuel changes, a new analysis is needed. The variation of fuel composition will tend to be far less for a given source over a period of time than that between different sources. For example, the composition of anthracite coal from one part of the country may differ considerably from that in another, but the anthracite mined from a specific location will tend to be fairly consistent throughout the seam. It is recommended that several fuel analyses be used for each fuel from a given source and that a weighted average carbon content be determined. The formula for calculating the CO2 emission factor is as follows:

$$EF = CC \times (44 / 12) \times E$$

Where:
EF = CO2 emission factor in mass/unit fuel
CC = Carbon content of fuel in mass/unit fuel (on a dry basis for solid fuels)
E = Fraction Oxidized (or combustion efficiency)
Note: The MW of CO2 is 44 and the atomic weight of carbon is 12

The Fraction Oxidized Can be obtained from Table 1 and the Carbon Content is the weighted average carbon content of the fuel estimated form fuel analyses.

The total CO_2 can then be calculated by multiplying the total quantity of fuel actually burned during the year by the emission factor EF, assuring the units for fuel are consistent. Care should also be taken to assure that the quantity factor used is the fuel that is burned rather than that purchased; this is particularly important for liquid and solid fuels that are stored in large quantities on-site.

4.1.2 Non-CO2 Emissions of GHGs from Combustion

Combustion of fossil fuels result in the trace generation of GHGs other than CO2, notably methane (CH4) and nitrous oxide (N2O). The quantity emitted for each will depend not only on the fuel, but also on the type of combustion system. To evaluate the significance of these emissions, the IMA-NA referred to the USEPA's *Draft* Climate Leaders Greenhouse Gas Inventory Protocol (August 19, 2002). Table A-1 provides approximate emission factors for fuels and economic sectors. The factors in (g/gJ-HHV) for industry are as follows:

- Coal CH4: 9.5 N2O: 1.33
- Petroleum Fuel CH4: 1.9 N2O: 0.57
- Natural Gas CH4: 4.5 N2O: 0.09

These factors can be converted to tons CO2e/MMBTU using the Global Warming Potentials (GWP) from the TAR (23 for methane and 296 for nitrous oxide) and the conversion factor for energy: 1.05506 gJ/MMBTU. The CO2 emissions for natural gas, petroleum distillate and subbituminous coal (the latter two chosen for "worst case" comparison) were calculated in units of (tons CO2/MMBTU). The following table illustrates the comparison of CO2 emitted and non-CO2 emissions stated as CO2e:

GHGs listed as Tons-CO2e/MMBTU

Fuel	CO2	CH4	N2O	Percent
Coal	0.1064	0.00025	0.000456	0.66%
Distillate Fuel Oil	0.08069	0.00005	0.000196	0.30%
Natural Gas	0.05854	0.00012	0.000031	0.26%

This analysis indicates that the largest contribution of non-CO2e for methane and nitrous oxide combined occurs with coal and is 0.66% of the CO2 emissions. This is a relatively trivial contribution compared to the error terms inherent in measuring fuel volumes and the precise carbon content of all fuels combusted. Therefore, this survey does not attempt to estimate the contribution of these non-CO2 emissions.

4.2 Allocation of GHGs for Combined-Heat-and-Power (CHP) Units

Participating companies operate CHPs and export electricity off-site and import steam from off-site CHPs. It is therefore necessary to allocate the GHGs emitted from the CHP between the electric power and the steam. The IMA-NA uses the guidance from the WBCSD/WRI "Calculating CO2 Emissions from Stationary Sources" (October 2001). Specifically, Option 1 for CHPs is applied to allocate GHGs between power and heat.

The equations used to calculate the GHGs attributable to the two forms of output are as follows:

$$EH = [(H/eh) / ((H/eh) + (P/ep))] \times ET$$

$$EP = ET - EH$$

Where:
ET = Total CO_2e emissions from CHP
EH = Amount of CO_2e attributable to Heat (steam)
EP = Amount of CO_2e attributable to Power (electricity)
H = Percentage of output that is Heat (steam)
P = Percentage of output that is Power
eh = Assumed efficiency of typical steam generation including transfer losses (75%)
ep = Assumed efficiency of typical power production including transmission losses (24%)

Note that $H + P < 1$; or $W = 1 - (H + P)$, where W = Percentage Waste

4.3 Process Emissions of CO2 in the Soda Ash Industry

The CO2 emissions from trona processing are covered in Chapter 2 of the IPCC's Revised 1996 Guidelines for National Greenhouse Gas Inventories: Reference Manual. The basic equation for processing trona to soda ash is as follows (note that the equation shown in the cited reference is not balanced):

$$\underbrace{2[Na_2CO_3\text{-}NaHCO_3\text{-}2H_2O]}_{\text{trona}} \rightarrow \underbrace{3Na_2CO_3}_{\text{soda ash}} + 5H_2O + CO_2$$

<u>Molecular Weights:</u>
$Na_2CO_3\text{-}NaHCO_3\text{-}2H_2O$ (trona) = 226.051
Na_2CO_3 (soda ash) = 106.004
H_2O (water) = 18.015
CO_2 (carbon dioxide) = 44.010

From this equation, it can be observed that it takes 10.27 tons of trona to produce 1 ton of CO2 (and 7.23 tons of soda ash). Two useful emission factors can be used in deriving estimates for process emissions:

- 0.097 tons CO2/ton trona
- 0.1384 tons CO2/ton soda ash

Other processing of soda ash and downstream products occur at participating sites. These processes invariably rely on stoichiometric reaction pathways, but may involve proprietary technologies and information. Sites are expected to perform the necessary calculations, taking these reaction pathways and process efficiencies into account to estimate process emissions. This work should be documented and stand up to independent engineering review.

4.4 Methane Emissions from Trona Mines

Several participating companies operate subsurface trona mines in Wyoming. The area also has fossil fuel deposits and the strata where trona is mined contain some oil shale and natural gas deposits. The natural gas escapes into the mines as ore is excavated. MSHA conducts quarterly testing of the mine ventilation system to monitor methane for fire safety. The shaft exhaust volume is approximated by measuring air flow velocity using a vane anemometer and multiplying the reading by the ventilation shaft's cross-sectional area.

The concentration of methane is measured using an electronic handheld gas meter. Concentrations are taken regularly (about weekly) as spot checks at various locations to prevent gas fires, but every quarter MSHA does a complete flow analysis of all ventilation shafts and tests methane concentration. Confirmatory methane testing is done periodically by taking an air sample in an evacuated glass tube. MSHA then analyzes the sample in its laboratory. Site personnel rely on MSHA data for both methane concentration and air flow to estimate total methane released.

The volume of exhaust tends to be relatively stable as is the methane concentration. A reasonable estimate of the total methane released can therefore be obtained from this approach. The CO2e is calculated by multiplying it by the Global Warming Potential (GWP).

Table 1 Default Values for Common Fuels

Fuel Name	Unit of Measure	High Heat Value[1], MMBTU/Unit	CO2 Factor[1], Tons/Unit	Assumed Fraction Oxidized[2]
Petroleum Fuels				
Aviation Gasoline	KGal	120.19	9.178	0.99
Distillate Fuel (No. 1, 2 4)	KGal	138.70	11.192	0.99
Diesel Fuel	KGal	138.70	11.192	0.99
Jet Fuel	KGal	135.00	10.548	0.99
Kerosene	KGal	135.00	10.769	0.99
Liquefied Petroleum Gas (LPG)	KGal	92.10	6.403	0.99
Motor Gasoline	KGal	125.07	9.782	0.99
Petroleum Coke	Ton	30.07	3.384	0.99
Residual Fuel (No. 5, 6)	KGal	149.70	13.017	0.99
Natural Gas and Other Gas Fuels				
Methane	MCF	1.01	0.0582	0.995
Landfill Gas	MCF	0.5	0.0289[3]	0.995
Flare Gas	MCF	1.11	0.0669	0.995
Natural Gas (Pipeline)	MCF	1.03	0.0603	0.995
Propane	KGal	91.03	6.335	0.995
Coal				
Anthracite	Ton	16.94	1.926	0.99
Bituminous	Ton	24.02	2.466	0.99
Subbituminous	Ton	17.47	1.858	0.99
Lignite	Ton	12.96	1.396	0.99
Renewable Sources				
Tires, Tire-derived Fuel	Ton	32.5	3.08	(*)
Wood and Wood Waste	Ton	16	1.56	0.90
Municipal Solid Waste	Ton	10	1.00	(*)

(1) USDOE Instructions for Form EIA-1605, Appendix B (March 2003)

(2) USEPA *Draft* Climate Leaders Greenhouse Gas Inventory Protocol (August 19, 2002)

(*) The oxidation efficiency for these fuels should be independently obtained. In the absence of any hard data, 0.90 may be used as an approximation.

APPENDIX A

INSTRUCTIONS FOR GREENHOUSE GAS INVENTORY WORKSHEET

APPENDIX A INSTRUCTIONS FOR GREENHOUSE GAS INVENTORY WORKSHEET

The survey tool for the Industrial Minerals Association - North America (IMA-NA) Greenhouse Gas (GHG) and Energy Survey is an EXCEL spreadsheet designed to assure consistency and rigor in compiling GHG emissions from the borates and soda ash industry. The worksheet also facilitates much of the calculations necessary to compile a company's inventory. Most of the instructions provided here are imbedded as comments in the worksheet. A blank worksheet for a fictitious "ABC Corporation" accompanies these instructions for reference. The reporting period for this worksheet is 2000 to 2005, with the initial survey covering the period from 2000 to 2002.

Participating companies should complete a worksheet for each applicable site or compile its information for all sites onto a single worksheet. Applicable sites include mining, materials handling, mineral processing, and chemical processing facilities involved in borates or soda ash.

Section 1. Direct Emissions of GHGs From Combustion Sources

Section 1 is used to capture all GHGs generated from major combustion sources on-site, including emissions associated with the production of steam and/or electricity that is exported off-site. Section 1 covers the following fuels, requiring input in the unit of measure specified:

- Natural gas, MCF (thousands of cubic feet, at 60 deg.F)
- Coal, Short Tons, dry basis
- Coke, Short Tons, dry basis
- Distillate Fuel Oil, K-Gal (thousands of gallons)
- Residual Fuel Oil, K-Gal
- Liquefied Petroleum Gas (LPG), K-Gal
- Gasoline, K-Gal
- Propone, K-Gal

There is a subsection provided for any other fuel that may have been consumed, requiring that the fuel be identified along with its unit of measure for quantity.

Each fuel has a default emission factor for GHGs entered. The units of measure for these factors are Short Tons of CO2-equivalent (CO2e) per the unit of measure used for that fuel. The defaults have been derived from the Department of Energy's GHG factors (Instructions for Form EIA-1605, Voluntary Reporting of Greenhouse Gases, Appendix B). The emission factor for coal is omitted since that number will depend on the type of coal. The DOE's default factors are provided in a comment field. The following are the DOE's default factors based on unit volume or mass of fuel:

- Natural Gas: 0.0603 Tons CO2e/MCF
- Anthracite: 1.926 Tons CO2e/Ton
- Bituminous: 2.466 Tons CO2e/Ton
- Subbituminous: 1.858 Tons CO2e/Ton
- Lignite: 1.396 Tons CO2e/Ton
- Coke: 3.3843 Tons CO2e/Ton
- Distillate Fuel Oil: 11.192 Tons CO2e/K-Gal
- Residual Fuel Oil: 13.017 Tons CO2e/K-Gal
- Liquefied Petroleum Gas (LPG): 6.403 Tons CO2e/K-Gal
- Gasoline: 9.782 Tons CO2e/K-Gal
- Propane: 6.335 Tons CO2e/K-Gal

You may enter your own emission factor in the "Emission Factor" column and note its source in the "Source of Factor" column.

Data should be entered in the "Quantity" section under the appropriate year. For each fuel, there are three cells for data. Enter the quantity of the fuel using the listed unit of measure in the top cell. The second cell down is optional; it is for the site's emission factor for that year, i.e., if the site calculates a new emission factor each year based on the physical parameters of the fuel, that factor can be entered in this cell. The third and last cell automatically calculates the CO2e emissions in tons. The algorithm first looks to see if there is an emission factor in the cell above it and, if yes, it will use that factor. If there is no factor entered in that cell, it will look for an emission factor in the "Emission Factor" column and use it to calculate CO2e emissions. If there is no factor in either cell, it will generate a "0.0" – most fuels have default emission factors provided, but you will need to enter a value for coal and any unlisted fuel entered in the row marked "Other". Finally, if you prefer to simply calculate the CO2e directly, you may do so and enter it in third cell (overwrite the formula). In this last instance, it is recommended that you enter the emission factor in the cell above (second cell) – you can also simply enter a formula in the second cell that calculates the emission factor: "={third cell containing CO2e}/{first cell containing quantity of fuel}."

Section 2. Indirect Emissions of GHGs From Imported Electric and Steam

Section 2 captures the CO2e emissions associated with electric power and imported steam used on the company's site or sites. The unit of measure for electricity is megawatt-hours (MW-Hr). Each site must obtain an emission factor in CO2e per MW-Hr from its power provider or, alternatively, use the DOE's default factor for the state where your site is situated (Instructions for Form EIA-1605, Voluntary Reporting of Greenhouse Gases, Appendix C). The sample form shows an entry for the Green River, WY area provided by PacificCorp's Salt Lake City office (0.91 tons CO2e/MW-Hr), slightly lower than the DOE's default factor for the State of Wyoming (1.073 tons CO2/MW-Hr).

Steam that is purchased from an off-site provider and used on-site is recorded in millions of pounds (MM-Lb). No emission factor is entered in the emission factor column, as that will need to be calculated or obtained from your steam provider. Care should be taken if the latter course is used – your provider may not be familiar with accepted GHG protocols and calculation methods. The following guidance can be used to obtain an emission factor for steam:

<u>Case 1. Steam from a Combined Heat-and-Power (CHP) Unit</u>
If the CHP personnel can provide an emission factor for their steam, ask whether they calculate it according to the World Business Council for Sustainable Development/World Resources Institute (WBCSD/WRI) Protocol. If so, ask them for the factor for steam and request a copy of their calculation method. If they don't have a factor based on WBCSD/WRI Protocol, ask them for the following numbers:

- Total fuel charged to the unit and the type of fuel; also request the total quantity of steam produced
- The output percentages for Heat, Power and Waste (e.g., a typical CHP may report 45% Heat, 35% Power and 20% Waste)
- (Alternative to the above information: obtain the total steam produced and the total electricity produced)

You now can calculate an emission factor:

1. Calculate the CO2e using DOE default emission factors.

2. Calculate the total heat input in MMBTU using the following DOE default energy content factors:
    a. Natural Gas: 1.01 Tons MMBTU/MCF
    b. Distillate Fuel Oil: 138.70 MMBTU/K-Gal
    c. Residual Fuel Oil: 149.70 MMBTU/K-Gal
    d. Petroleum Coke: 30.07 MMBTU/Ton
    e. Coal, Anthracite: 16.94 MMBTU/Ton
    f. Coal, Bituminous: 24.02 MMBTU/Ton
    g. Coal, Subbituminous: 17.47 MMBTU/Ton
    h. Coal, Lignite: 12.96 MMBTU/Ton

3. If you obtained total steam and power produced rather than the percentage of output, convert fuel input, steam output and power output into a common energy unit and calculate the %Heat, %Power and %Waste.

4. If the CHP did not provide the amount of steam produced, estimate it using the heat of condensation for steam: 900 MMBTU/MM-Lb. The formula to estimate the steam output is:

    Q steam MM-Lb = (%Heat) x (Total Heat Input, MMBTU) / (900 MMBTU/MM-Lb)

5. Calculate the percentage of the CO2e attributable to the steam using the following equation:

    EH = [(H/eh) / ((H/eh) + (P/ep))]

    Where:
    EH = Fraction of CO2e attributable to Heat (steam)
    H = Percentage of output that is Heat (steam)
    eh = Assumed efficiency for steam generation including transfer losses (75%)
    P = Percentage of output that is Power
    ep = Assumed efficiency for electric power including transmission losses (24%)

6. Calculate Total CO2e attributed to Heat (steam) by multiplying EH x Total CO2e

7. Divide the Total CO2e attributed to Heat (Steam) by the Total Steam produced in MM-Lb

The “assumed efficiencies” for steam and power generation are the typical efficiencies observed for stand-alone steam production and power production facilities including losses associated with steam conveyance and power transmission. The WBCSD/WRI guidance tool “Calculating CO2 Emissions for Stationary Sources” (October 2001) does not explicitly recommend a value for either, but in a sample calculation, the guidance uses 24% assumed efficiency for power generation and transmission. This value appears reasonable and has been adopted for the IMA-NA Soda Ash/Borates Industry Inventory. The California Climate Action Registry (CCAR) relies on the WBCSD/WRI guidance, but explicitly recommends that 75% be used for the overall efficiency of steam generation. This protocol therefore adopts 75% for the assumed efficiency of heat generation and transport.

<u>Case 2 Steam from a Dedicated Steam Boiler</u>
This calculation is more straight-forward than that for a CHP – if the steam provider has an emission factor, you can use that. Alternatively, you request the total fuel used and total steam generated and, using DOE default emission factors, calculate the CO2e generated and divide it by the steam produced to get the emission factor. Finally, if the steam producer will not provide any detailed information, you can estimate an emission factor if you know the fuel being used:

1. Obtain the fuel being used and get the appropriate default DOE emission factor for that fuel in Tons CO2e/MMBTU. The factor for major fuel types are as follows:

    i. Natural Gas: 0.05854 Tons CO2e/MMBTU
    j. Distillate Fuel Oil: 0.08069 CO2e/MMBTU
    k. Residual Fuel Oil: 0.08695 Tons CO2e/MMBTU
    l. Petroleum Coke: 0.1126 Tons CO2e/MMBTU
    m. Coal, Anthracite: 0.1137 Tons CO2e/MMBTU
    n. Coal, Bituminous: 0.1027 Tons CO2e/MMBTU
    o. Coal, Subbituminous: 0.1064 Tons CO2e/MMBTU
    p. Coal, Lignite: 0.1077 Tons CO2e/MMBTU

2. Assuming the steam is saturated, the latent heat of condensation for steam can be used to approximate the heat content: 900 MMBTU/MM-Lb.

3. Assume a total efficiency for the steam production and conveyance of 75%; divide the heat content of the steam by this efficiency to get the estimate of heat input: 1,200 MMBTU/MM-Lb.

4. Multiply this heat input factor by the appropriate emission factor in number 1 above. The resulting emission factors for dedicated steam boilers are as follows:
    a. Natural Gas: 75.25 Tons CO2e/MM-Lb Steam
    b. Distillate Fuel Oil: 96.83 Tons CO2e/MM-Lb Steam
    c. Residual Fuel Oil: 104.34 Tons CO2e/MM-Lb Steam
    d. Petroleum Coke: 135.12 Tons CO2e/MM-Lb Steam
    e. Coal, Anthracite: 136.44 Tons CO2e/MM-Lb Steam
    f. Coal, Bituminous: 123.24 Tons CO2e/MM-Lb Steam
    g. Coal, Subbituminous: 127.68 Tons CO2e/MM-Lb Steam
    h. Coal, Lignite: 129.24 Tons CO2e/MM-Lb Steam

Entry of energy values in the Quantity section is identical to that in Section 1, the top cell for each category is for the units of energy and the second is for a year-specific emission factor (optional).

Section 3. Direct Emissions of GHGs From Exported Electric and Steam

Just as the GHGs derived from imported energy is added to the site's inventory, GHGs generated to produce steam or electric that is exported are subtracted. The procedure for allocating the CO2e between steam and power is explained in Section 2, Case 1. To obtain the CO2e for electricity, calculate EP (the fraction of CO2e attributable to power) by simple subtraction: EP = 1 – EH. The information needed to perform these calculations should be readily available. The conversion factor to convert MW-Hr to MMBTU is: 3.413 MMBTU/MW-Hr. Data are entered in the Quantity section as described in Sections 1 and 2.

Section 4. Process Emissions of GHGs

Process emissions of GHGs include CO2 and other chemicals that have been identified as having global warming potential that are emitted as a result of mining, mineral processing or chemical processing at company sites. The major emissions in this category include the methane in natural gas that leaks from rock strata in underground trona mines and are swept out of the mine shaft. Routine testing is performed to satisfy MSHA requirements, and these data are used to calculate methane emissions. Another major process emission is the natural CO2 contained in trona that is released during processing of trona ore into soda ash and related chemicals. These emissions are stoichiometric in nature and can be readily estimated based on the chemical processes taking place on the site. Process emissions of non-CO2 GHGs are converted into CO2-equivalent (CO2e) by multiplying the quantity of chemical released by its Global Warming Potential (WMP) factor. The GWP factors used by the IMA-NA are consistent with those currently being used by the American Chemistry Council (ACC) and are taken from the Intergovernmental Panel on Climate Change (IPCC) Third Assessment Report (TAR) (see Tables 4.1(a) and (b), pp. 244-245).

Section 5. Removal and Replacement of Forest Lands

Member companies should report any significant removal or planting of forestland. Three categories of activities are collected in Section 5:

- Afforestation: This is the annual carbon sequestration associated with forestation of land that has been clear since before 1990. This value is recorded as a negative number.
- Reforestation: This is the annual carbon sequestration associated with forestation of land that was deforrested during or after 1990. This value is also recorded as a negative number.
- Deforestation: This is the annual carbon sequestration associated with forest land that has been removed during the reporting year. This value is recorded as a positive number.

It is important to recognize that the entries in this table reflect the change in annual carbon sequestration, reported as CO2e, for that year. The loss of carbon sequestration from a deforestation activity is recorded in that year. The following year, no entry is made with regard to that activity; however, the bottom line of the table, “NET Cumulative GHGs” would reflect that earlier number. This loss of carbon sequestration is a constant value, as estimated in the year it was recorded, that applies to all subsequent years.

A gain in carbon sequestration (afforestation and reforestation) is somewhat more complex. As in the case of deforestation, you must enter a number for the estimated annual amount of carbon that is sequestered by the new plantings. That value is also applied in the “NET Cumulative GHGs” for all subsequent years. However, as the new growth develops, the amount of carbon sequestered may change – generally the rate of carbon sequestration will increase for many years and then plateau. If you recalculate the annual carbon sequestration rate for each subsequent year, enter ONLY the change in annual carbon sequestration from the previous year (again, as CO2e).

For example, suppose you complete an afforestation project in 2000 and you estimate a carbon sequestration rate of 1,000 tons CO2e/year for the initial growth. Further, you determine that the actual sequestration was only about 40% of this rate because growth did not begin until around late spring. You would therefore enter 400 tons CO2e in the Afforestation cell in the column for 2000. The following year, you believe the rate to be still around 1,000 tons CO2e/year but it was effective for the full year; you would therefore enter 600 tons CO2e for

2001 since sequestration for this project has increased from 400 tons CO2e/year to 1000 tons CO2e/year. If in the following year, you have an independent assessment done and the study indicates that the maturing growth now is sequestering carbon at a rate of 1,300 tons CO2e/year, you would enter 300 tons/year for 2002 since that is the change from 2001.

For guidance on how these projects should addressed, see the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual, Chapter 5.

Section 6. Production

Each company should enter the total tons of product produced by its operations. Some product lines are produced at member sites that are not soda ash, borates or related compounds but the GHGs associated with their manufacture and handling cannot easily be subtracted from the inventory because they rely on common energy sources at the site. These product streams are relatively small. The production quantity of these products should be included in Section 6 since the energy and GHGs associated with their manufacture are included in the previous sections of the worksheet.

Each company should document its methodology for calculating total production. Care should be taken to avoid double-counting production. Total production is the total quantity of all products produced at soda ash or borate facilities (on a dry basis) and shipped to internal or external customers.

IMA-NA GREENHOUSE GAS AND ENERGY SURVEY – INDUSTRY SUMMARY

1. DIRECT EMISSIONS OF GREENHOUSE GASES (GHGs) -- [Includes electric and steam exported off-site]

Fuel or Energy Type	Unit of Measure	GHG	Units of Factor	Emission Factor	Source of Factor	Quantity					
						2000	2001	2002	2003	2004	2005
Natural Gas	MCF										
					Site calc. =						
	Tons	CO2e	T/MCF	0.0601	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Coal	Tons										
					Site calc. =						
	Tons	CO2e	T/T		DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Coke	Tons										
					Site calc. =						
	Tons	CO2e	T/T	3.3843	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Distillate Fuel Oil	K-Gal										
					Site calc. =						
	Tons	CO2e	T/K-Gal	11.192	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel Oil	K-Gal										
					Site calc. =						
	Tons	CO2e	T/K-Gal	13.0165	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Liquefied Petroleum Gas	K-Gal										
					Site calc. =						
	Tons	CO2e	T/K-Gal	6.4025	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Gasoline	K-Gal										
					Site calc. =						
	Tons	CO2e	T/K-Gal	9.782	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Propane	K-Gal										
					Site calc. =						
	Tons	CO2e	T/K-Gal	6.3345	DOE Default	0.0	0.0	0.0	0.0	0.0	0.0
Other:											
					Site calc. =						
	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
TOTAL DIRECT GHGs	TONS	CO2e				**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

2. INDIRECT EMISSIONS OF GREENHOUSE GASES (GHGs) -- From imported electric and steam

Fuel or Energy Type	Unit of Measure	GHG	Units of Factor	Emission Factor	Source of Factor	Quantity					
						2000	2001	2002	2003	2004	2005
Electricity purchased	MW-Hrs										
					Site calc. =						
	Tons	CO2e	T/MWhr	0.91	Pacificorp	0.0	0.0	0.0	0.0	0.0	0.0
Steam purchased	MM-Lb										
					Site calc. =						
	Tons	CO2e	T/MM-Lb	35		0.0	0.0	0.0	0.0	0.0	0.0
TOTAL INDIRECT GHGs	TONS	CO2e				**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

3. DIRECT EMISSIONS OF GHGs FROM EXPORTED ENERGY -- [Electric and steam exported off-site]

Fuel or Energy Type	Unit of Measure	GHG	Units of Factor	Emission Factor	Basis of Calculation	Quantity					
						2000	2001	2002	2003	2004	2005
Electricity exported	MW-Hrs										
					Site calc. =						
	Tons	CO_2e	T/MWhr		WRI-WBCSD	0.0	0.0	0.0	0.0	0.0	0.0
Steam exported	MM-Lb										
					Site calc. =						
	Tons	CO_2e	T/MM-Lb		WRI-WBCSD	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL EXPORTED GHGs	TONS	CO_2e				0.0	0.0	0.0	0.0	0.0	0.0

4. PROCESS EMISSIONS OF GREENHOUSE GASES (GHGs)

Process GHG Emissions	Unit of Measure	GHG	CO_2e Factor		Source of Factor	Quantity					
						2000	2001	2002	2003	2004	2005
CO_2	Tons										
	Tons	CO_2e	1		ACC	0.0	0.0	0.0	0.0	0.0	0.0
Methane (CH_4)	Tons										
	Tons	CO_2e	23		ACC	0.0	0.0	0.0	0.0	0.0	0.0
Nitrous Oxide (N_2O)	Tons										
	Tons	CO_2e	296		ACC	0.0	0.0	0.0	0.0	0.0	0.0
HFC-23	Tons										
	Tons	CO_2e	12,000		ACC	0.0	0.0	0.0	0.0	0.0	0.0
HFC-125	Tons										
	Tons	CO_2e	3,400		ACC	0.0	0.0	0.0	0.0	0.0	0.0
HFC-134a	Tons										
	Tons	CO_2e	1,300		ACC	0.0	0.0	0.0	0.0	0.0	0.0
HFC-152a	Tons										
	Tons	CO_2e	120		ACC	0.0	0.0	0.0	0.0	0.0	0.0
HFC-227ea	Tons										
	Tons	CO_2e	3,500		ACC	0.0	0.0	0.0	0.0	0.0	0.0
Other HFCs	Tons										
	Tons	CO_2e				0.0	0.0	0.0	0.0	0.0	0.0
Perfluoromethane (CF_4)	Tons										
	Tons	CO_2e	5,700		ACC	0.0	0.0	0.0	0.0	0.0	0.0
Perfluoroethane (C_2F_6)	Tons										
	Tons	CO_2e	11,900		ACC	0.0	0.0	0.0	0.0	0.0	0.0
Sulfur Hexafluoride (SF_6)	Tons										
	Tons	CO_2e	22,200		ACC	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PROCESS GHGs	TONS	CO_2e				0.0	0.0	0.0	0.0	0.0	0.0

IMA-NA GREENHOUSE GAS AND ENERGY SURVEY – INDUSTRY SUMMARY

5. REMOVAL AND REPLACEMENT OF FOREST LANDS -- On-site or validated off-site activity

CO2 Sequestration	Unit of Measure	GHG	Basis for CO2e impact estimate	Quantity* 1990 - 1999	Quantity 2000	2001	2002	2003	2004	2005
Afforestation (negative)	Tons	CO2e								
Reforestation (negative)	Tons	CO2e								
Deforestation (positive)	Tons	CO2e								
NET Change in GHGs	Tons	CO2e		0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET Cumulative GHGs	TONS	CO2e		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: Cells that are highlighted in red have the wrong sign!

6. PRODUCTION VOLUME

	Unit of Measure		Quantity 2000	2001	2002	2003	2004	2005
Total Production Volume	Tons							

Site Notes:

IMA-NA GREENHOUSE GAS AND ENERGY SURVEY – INDUSTRY SUMMARY

A. SUMMARY OF GHG ACTIVITY

CATEGORY OF GHG	Unit of Measure	GHG				Quantity					
						2000	2001	2002	2003	2004	2005
Direct GHGs - Energy	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
Process GHGs	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL - DIRECT GHGs	Tons	CO2e				**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
GHGs Exported Off-site	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
SUB - NET DIRECT GHGs	Tons	CO2e				**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Indlrect GHGs - Energy	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
Net GHGs - Forestry	Tons	CO2e				0.0	0.0	0.0	0.0	0.0	0.0
NET TOTAL GHGs	Tons	CO2e				**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

IMA-NA GREENHOUSE GAS AND ENERGY SURVEY – INDUSTRY SUMMARY

B. ENERGY SUMMARY

Fuel or Energy Type	Units MMBTU/	Conv. Factor	Source of Factor	Quantity, MMBTU 2000	2001	2002	2003	2004	2005
Natural Gas			Site calc. =						
	MCF	1.03	DOE default	0	0	0	0	0	0
Coal			Site calc. =						
	Ton	24	ACC	0	0	0	0	0	0
Coke			Site calc. =						
	Ton	30.1	DOE default	0	0	0	0	0	0
Distillate Fuel Oil (Nos. 1, 2, 4 and Diesel)			Site calc. =						
	K-Gal	138.7	DOE default	0	0	0	0	0	0
Residual Fuel Oil (No. 5 and No. 6 Fuel Oil)			Site calc. =						
	K-Gal	149.7	DOE default	0	0	0	0	0	0
Liquefied Petroleum Gas (LPG)			Site calc. =						
	K-Gal	92.1	DOE default	0	0	0	0	0	0
Gasoline			Site calc. =						
	K-Gal	125.1	DOE default	0	0	0	0	0	0
Propane			Site calc. =						
	K-Gal	91.0	DOE default	0	0	0	0	0	0
			Site calc. =						
				0	0	0	0	0	0
SUBTOTAL - ENERGY PRODUCED				**0**	**0**	**0**	**0**	**0**	**0**
Electricity exported			Site calc. =						
	MWh			0	0	0	0	0	0
Steam exported			Site calc. =						
	MM-Lb			0	0	0	0	0	0
SUBTOTAL - EXPORTED ENERGY				**0**	**0**	**0**	**0**	**0**	**0**
NET DIRECT ENERGY CONSUMED				**0**	**0**	**0**	**0**	**0**	**0**
Electricity imported			Site calc. =						
	MWh	10	ACC	0	0	0	0	0	0
Steam imported			Site calc. =						
	MM-Lb		Site calc.	0	0	0	0	0	0
SUBTOTAL - ENERGY IMPORTED				**0**	**0**	**0**	**0**	**0**	**0**
TOTAL NET ENERGY CONSUMED				**0**	**0**	**0**	**0**	**0**	**0**